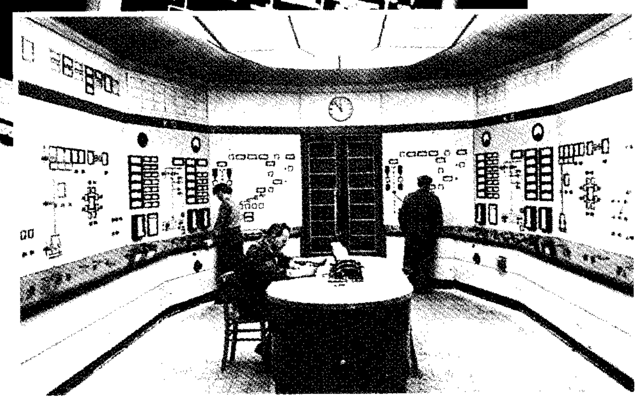
SPECIAL REPORT

Backfitting powerplant control systems

Both nuclear and fossil-fuel-based power producers are striving to revamp antiquated controls with advanced, digital-based systems. New technology promises to maximize availability, minimize emissions, and optimize processes. But success means that outdated ways of thinking, like old hardware, must be tossed aside



1. Backfitting digital I&C into 30- to 40-yr-old steam plants can extend their service life. At the heart of the most successful backfit projects are tangible improvements in control strategies, high-fidelity simulators, and human/machine interface

By Robert Swanekamp, PE, Associate Editor

An overwhelming majority of US electric capacity still comes from large, centralized Rankine-cycle stations, though that reality is sometimes lost in the din of press releases trumpeting newly installed gas turbines. Most of these venerable steam plants, both fossil-fired and nuclear, will be 30 years or older by the end of this decade. In more genteel times, these plants would be ambling along under well-established operating conditions or gracefully heading for retirement. But the brave, new competitive marketplace is pressing these 30-something plants into extended service under radically new operating requirements—tighter environmental restrictions, more load maneuverability, shorter maintenance outages, decreasing budgets, and so on.

In response, power producers are re-engineering their aging stations armed with competitive management strategies (POWER, August 1995, p 13) and new technologies—one of the most powerful of which is digital-based instrumentation and control (I&C). For the aging steam plant, backfitting digital I&C systems promises:

- Faster plant startup and shutdown by programming control sequences.
- Higher availability by detecting and pinpointing root causes of impending malfunctions.
- Higher thermal efficiency by moving variable setpoints closer to the operating limits.
- Improved emissions profile by precisely controlling the combustion and downstream cleanup processes.
- Lower maintenance costs by eliminating antiquated pneumatic, electromechanical, or electronic/analog devices.
- Lower operating costs by reducing staff requirements—today's designers are even striving for single-operator control of coal-fired powerplants.

Nuclear plants are in particular need of control system updates. With only a few exceptions, virtually all I&C equipment in US nuclear powerplants is based on obsolete analog devices. While digital equipment offers enormous potential benefits for these plants, backfitting the new technology is especially time- and capital-intensive because of regulatory/licensing hurdles. (see box, next page).

Whether nuclear- or fossil-based, droves of power producers are earnestly "going digital," and not just in limited applications—such as steam-temperature

Clearing the path for nuclear backfits

Most commercial nuclear powerplants in the US were designed 20 to 40 years ago, and today, most continue to operate with the original analog or electromechanical I&C systems. The equipment is approaching—or has already exceeded—its design life expectancy, resulting in increased maintenance and reduced reliability. Surveys of licensee event reports (LERs), for example, show that a majority of the LERs are related to I&C issues. Understandably then, the issues of I&C reliability and obsolescence have emerged as high priorities in the industry.

Backfitting with digital-based controls is the obvious solution, and manufacturers of the original I&C systems—principally GE Nuclear Energy, San Jose, Calif; Westinghouse Electric Corp, Pittsburgh, Pa; and ABB Combustion Engineering Nuclear Operations, Windsor, Conn—have introduced new controllers, signal conditioners, and power supplies specifically designed for the task. Through features such as "plug-to-plug" compatibility and open communications protocols, nuclear I&C upgrades appear to be even more feasible than upgrades at fossil-fuel-based plants (figure).

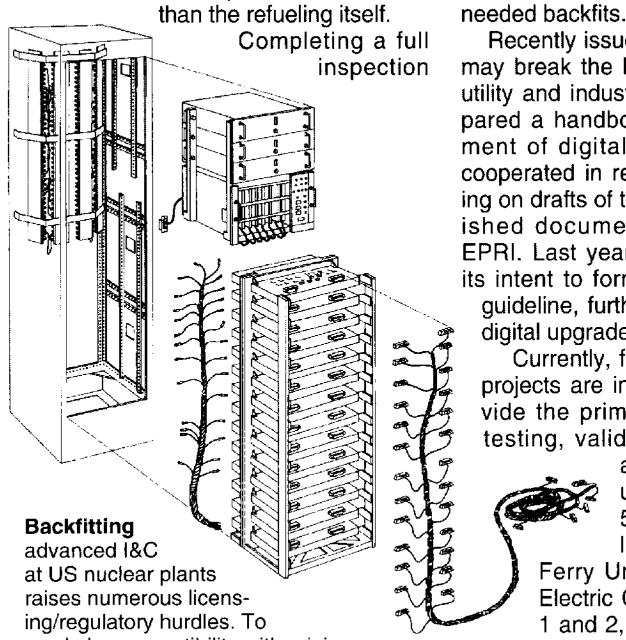
But I&C backfitting is not a straightforward exercise for US nuclear stations, because of the serious safety issues involved and strict regulatory oversight. While digital upgrades have been implemented at nuclear plants in Europe and Asia, US nuclear utilities face challenging licensing issues, such as:

- Validation and verification of software.
- Effects of electromagnetic interference (EMI) and seismic activity.
- Security of information transmitted through advanced communications networks.
- Control of configuration changes.
- Fault tolerance and true redundancy.
- Clarity of human/machine interface (HMI).

Understanding CFR

To backfit a nuclear plant with digital I&C, utilities must choose between two options: First option is to obtain approval of the Nuclear Regulatory Commission (NRC) through the long, tortuous path of full inspection and Safety Evaluation Report (SER). This path recently was followed by the Donald C Cook nuclear plant, located in Bridgman, Mich, when the reactor protection and control instrumentation on Units 1 and 2 were backfitted.

The NRC performed an inspection in 1993, and issued an SER in 1994. Subsequently, digital-based controls for both units were tested, installed, and started up during recent refueling outages, reportedly without a glitch. The installations went so smoothly, that both backfits were completed in less time than the refueling itself.



Backfitting advanced I&C at US nuclear plants raises numerous licensing/regulatory hurdles. To maximize compatibility with original systems, manufacturers offer digital upgrades that fit existing cabinets and use original field wiring and terminations

Completing a full inspection and SER is the path now being followed by most US nuclear utilities, but a second option is established in Title 10 of the Code of Federal Regulations (10 CFR 50.59). The code allows changes to be made without prior approval of the NRC if, among other conditions, there are no unreviewed safety questions (USQs). USQs are defined in terms of increasing probability or consequences of an accident or malfunction, relating the possibility of a new type of failure or decreasing safety margins. The licensee is responsible for performing a safety evaluation to determine whether USQs exist.

Unfortunately, interpreting 10 CFR 50.59 has proved difficult for utilities. They cannot determine confidently when NRC review will be required and what acceptance criteria will be used. As a result, utilities have opted for the SER route, or have delayed the much-needed backfits.

Recently issued guidelines, however, may break the logjam. A committee of utility and industry representatives prepared a handbook to clarify the treatment of digital upgrades. The NRC cooperated in reviewing and commenting on drafts of the handbook, and a finished document was published by EPRI. Last year, the NRC announced its intent to formally endorse the new guideline, further clearing the way for digital upgrades.

Currently, five utility demonstration projects are in progress that will provide the primary inputs, as well as testing, validation, and refinement activities for digital I&C upgrades under 10 CFR 50.59: Tennessee Valley Authority's Browns Ferry Unit 2, Baltimore Gas & Electric Co's Calvert Cliffs Units 1 and 2, Northern States Power Co's Prairie Island Units 1 and 2, Entergy Corp's Arkansas Nuclear One, and Omaha Public Power District's Fort Calhoun.

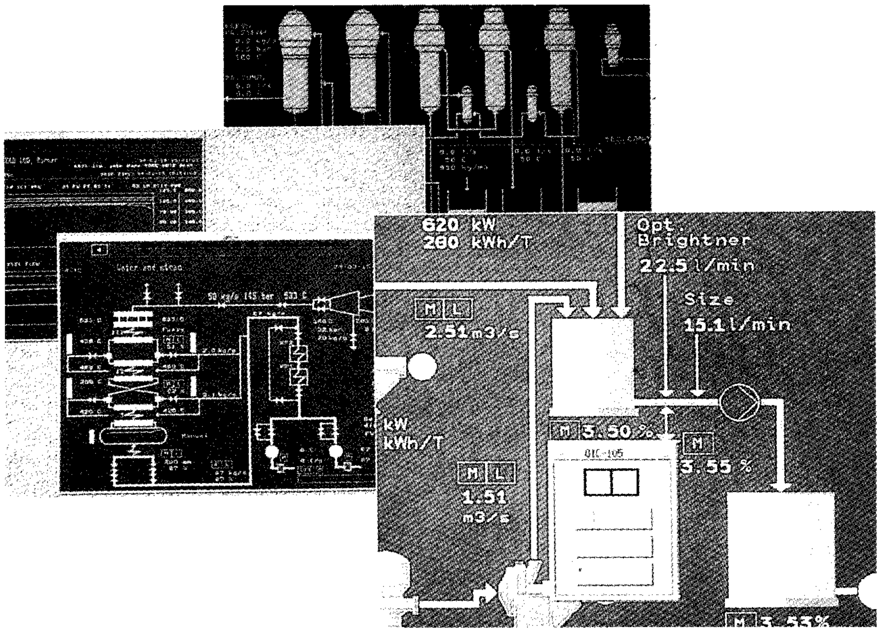
or feedwater-flow control. Today's retrofit projects typically cover the entire plant, are driven by corporate planners, and are funded by large capital budgets. While each backfitting project features its own distinct hardware, software, and design philosophy, one overriding message stands out: After a slow start in the tradition-steeped power industry, digital-based I&C is now infiltrating control rooms across North America (Fig 1).

Digital, at last

Traditional powerplant design calls for conservative engineering using well-proven equipment. This thinking, justified under the tenet of "obligation to serve," has slowed the introduction of digital-based control systems in the power industry, compared to, say, the manufacturing or petrochemical sectors.

In the early days of microprocessors, powerplant designers questioned whether computer hardware was sufficiently reliable to serve for many years of continuous duty. Another concern was the reliability of application software—whether the software that's customized for each installation would be robust enough without endless verification testing.

But over the past 10 years or so, two fundamental changes, like reinforcing ocean waves, have joined together to spur the industry's acceptance of microprocessors: (1) Computer capability, as the business journals incessantly remind us, has plummeted in cost and skyrocketed in standardization. It is now practical to monitor large amounts of data, apply sophisticated control algorithms, and run lengthy analyses on affordable, off-the-shelf personal computers or workstations; and (2) deregulation makes computer capability particularly appealing—even essential—to powerplants facing a competitive future.



2. Windows-based software enables operators to simultaneously display several different systems and plant processes on the same CRT screen, eliminating one of the major drawbacks to digital I&C

Consider that today's powerplant operator must, among other things, simultaneously maintain prescribed emissions, cycle the unit to maximize profitability, monitor real-time production costs, including operation and maintenance (O&M) expenses, and burn a wide mix of fuels. Contrast this to a decade ago, when a plant burned one type of fuel, met an annually tested emissions limit, operated base-load, and tallied all production costs only before the next rate case.

Tangible improvements

Further spurring the drive to backfit digital I&C systems are a handful of specific technical improvements—true, commercially proven advancements that stand out from the barrage of bells and whistles described by obtuse, ever-changing technical jargon from suppliers. Following is a sample of these advancements, along with profiles of backfiring projects that have successfully applied the technologies. For a complete review of today's information technology, see POWER special report, June 1995, "Information Technology for Powerplant Management."

Improved HMI

One of the drawbacks to early digital systems was that the human/machine interface (HMI)—the familiar CRT screen—could depict only part of the available plant information at one time. Compared to the sweeping, wall-to-wall instrument panels of yore, CRTs offered only a restricted, narrow view of the process. One solution gaining acceptance is to install a large-screen display, adjacent to multiple, smaller CRTs. By displaying overview information, large screens provide a more complete view of the process to augment the detailed information shown on individual CRT screens. Large displays also can be seen by the entire control-room crew, improving team coordination and decision-making. Recent improvements in price, resolution, brightness, and durability make large-screen displays a viable option for control-system retrofits.

One common type of large-screen display is the self-contained unit. Featuring a 60- to 70-in. diagonal screen, the self-contained unit requires a 6-ft-high × 5-ft-wide × 3-ft deep cabinet. Other types of large-screen displays use front or rear projectors, allowing the screen and projector to be located separately.

Optimal choice for each application depends on the space available, room lighting, viewer distance and angle, and desired screen images. Although self-contained units are compact and offer superior image brightness, the screen size, field-of-view, and resolution are limited. Front- or rear-projector models may be appropriate if sufficient space is available, and a brighter image, higher resolution, or wider viewing angle is needed. Typically, the cost of a large-screen display increases with image brightness and resolution.

A window to the process

Another tangible improvement in HMI stems from the latest generation of Windows-based software. Windows software enables operators to simultaneously display several different systems and plant processes on the same screen, giving them quicker access to large amounts of plant information (Fig 2).

Windowing capabilities were at the heart of an I&C backfit recently completed at Tucson Electric Power Co's Irvington station. Irvington comprises four oil/gas-fired units, one of which had been converted to coal and updated in 1985. Units 1-3, however, still used 1950s-vintage control systems, so the utility recently decided to backfit.

Scope of the original project was limited to upgrading the boiler's combustion, feedwater, steam-temperature, and flame-safety control systems. After more detailed studies were conducted, the utility widened the scope to implement a plant-wide distributed control system (DCS).

Concerned about HMI, Tucson Electric decided that the DCS consoles should have windows technology, with the capability of displaying numerous pages on one screen. Planners specified a WDPF DCS with

3. El Segundo station, built in 1955, has pioneered multivariable control technology. In a project completed last summer, El Segundo backfit the technology for the historically tough challenge of steam-temperature control in a reheat steam cycle in Units 3 and 4

4. Bergen station operators updated a 1960s-vintage control system and found that a simulator can streamline backfit projects. Engineers originally ordered the simulator for operator training, but also used it to identify construction errors before commissioning

WEStation consoles, a newly released operator interface supplied by Westinghouse Electric Corp, Process Control Div, Monroeville, Pa. The system includes four CRTs per unit, each unit being independent from the others.

Now that the project is completed, Tucson Electric operators can display four screens on a single CRT, and can rapidly switch back and forth without calling up new screens. As operators have gained more experience and grown more comfortable with the system, they have added more information to the screens: trend overlays on process displays, group display overlays on process graphics, and performance graphic displays.

Multivariable control

Multivariable controllers represent a step change in digital I&C technology. Although successfully used by the process industry for several years, this advanced technology is just now being applied in powerplants. The promise of multivariable control is so great, that one expert predicts the technology "will relegate proportional-integral-derivative (PID) controllers to the Smithsonian" within a decade.

Conventional control technologies incorporate PID schemes to respond to process changes in one of two methods. The most common method moves one manipulated variable to respond to changes in one process variable. This is referred to as single-input/single-output control (SISO). The alternative method moves one manipulated variable to respond to changes in two or more process variables. This is referred to as multiple-input/single-output control (MISO). Three-element feedwater control, familiar to most powerplant operators and engineers, is an example of MISO.

Both SISO and MISO strategies have drawbacks. SISO technology is inherently limited to simple, one-variable processes, or processes that can be approximated as such. MISO controllers can handle complicated processes, but they add complexity in control logic, and they require regular retuning as the process response changes over time. The advent of DCS has given design engineers additional tools, but those systems merely coordinate the activity of many SISO and MISO controllers. Even when all of these conventional tools are combined, they cannot precisely control a highly dynamic, highly interactive process.

Multivariable controllers, in contrast, are multiple-input/multiple-output (MIMO) devices—simultaneously adjusting two or more manipulated variables in response to changes in two or more process variables. MIMO devices apply calculations and logic based on models and control objectives specified by the designer. The models, created from system response tests, enable the controller to predict the effects of process disturbances and to compensate for dead time and process time constants. These advanced systems have broader objectives and can respond more precisely than conventional PID controllers. And, unless major plant modifications are made, tuning of these MIMO devices is usually straightforward, requiring adjustment of steady-state gain and reference time.

El Segundo's experience

The 1950s-vintage El Segundo station, owned by Southern California Edison Co (SCE), is one of the pioneers of multivariable control technology. In a project completed last summer, El Segundo backfit the technology for the historically tough challenge of controlling steam temperature in a reheat steam cycle (Fig 3).

Software called Idcom B, developed by Bailey Controls Co, Wickliffe, Ohio, is at the heart of El Segundo's multivariable controller. The software package resides in the same process control unit as the conventional steam-temperature control logic, eliminating the expense and complication associated with additional, external computers.

Once the system was installed, it was brought on-line by placing individual loops under control of the Idcom-B one at a time to verify functionality before proceeding to the next loop. An important step in the verification process was the intentional introduction of small disturbances to observe settling time. As the number of variables under Idcom-B control increased, steam-temperature control noticeably improved, with reduced magnitude and duration of temperature excursions.

Improved temperature control was most evident during the latter stages of commissioning when brief tests were conducted to compare the new system to the conventional controls. With the unit under sliding pressure control, load was ramped from 40 to 100% at a rate of 2%/min. Both the conventional and the multivariable controllers experienced overshoot of 12 to 15 deg F, but the new controllers recovered quickly, while the conventional system oscillated indefinitely between +10 deg F. Next, the unit was subjected to repeated load changes of 20% up and down. The multivariable system maintained steam temperatures near setpoint, with brief spikes of +4 deg F. In contrast, the conventional system completely failed to control, and manual intervention was eventually required to restore system stability.

Although these initial results were promising, operating experience with the multivariable controllers is still limited, according to Tom Cook, El Segundo's supervisor of plant instrumentation. Echoing the experience of many in the industry, Cook reports that aging, imprecise field devices have significantly reduced the time the advanced controllers can be used.

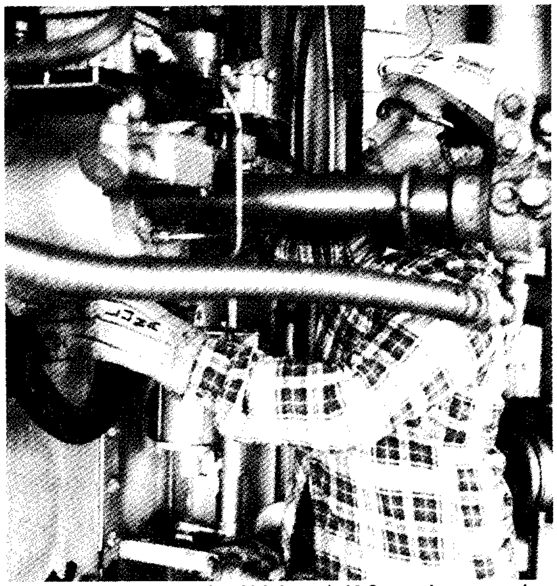
Realistic simulators

High-fidelity simulators represent another tangible advancement in I&C. Latest generation of simulators are able to mitigate some of the problems associated with an older plant's sudden shift to digital technology.

For example, simulators can enhance the design process: First, by extracting operator feedback on proposed graphic displays and icon layouts, and second, by testing out system changes before they are actually drawn into the plans. Because each powerplant has unique characteristics, wiring and hardware changes that may seem generic can necessitate unforeseen modifications. But a simulator based on the projected DCS configuration provides an excellent testbed for such engineering changes.

Simulators are also proving valuable in operator training. For starters, operators can become familiar with new touchscreens and keyboards without risking plant upsets or equipment damage. Also, simulators allow operators to practice startups, shutdowns, and transient operation without wasting precious fuel. Typically, simulators enable an instructor to initiate system and process disturbances such as:

- Equipment trip/failure to operate.
- Transmitter/sensor failure.
- Process-variable deviation/excursion.
- Failure of a DCS data station.
- Failure of a CRT screen.
- Heating-value variation in fuel.
- Load dispatch requirements.
- Boiler tube leak.



5. Successful backfit of high-tech I&C requires attention to low-tech issues, too. Examples: (1) calibration, repair, or replacement of sensors and final-control elements, and (2) operator involvement in the project

'I needed it yesterday'

Public Service Electric & Gas Co's (PSE&G) Bergen station, a recently repowered 650-MW facility in Ridgefield, NJ, updated its 1960s-vintage control system and found that a simulator streamlined the backfit project. Bergen engineers ordered the simulator from Framatome Technologies, Lynchburg, Va, primarily for operator training (Fig 4). But as the simulator was being programmed, design flaws were discovered through validation and verification of plant specifications, allowing construction errors to be corrected before plant commissioning.

Jack Witkowski, simulator project manager for PSE&G, wishes they had the simulator delivered even earlier. "We could have shaken out the systems thoroughly," he says, "as well as given the operators more input on DCS graphics and screens."

Open this architecture

For years, a rallying cry for digital I&C users has been "less proprietary systems and more interoperability." Instrument vendors, in turn, have promised "standards-based products soon," and have even established the Fieldbus Foundation to develop one international specification. The fieldbus standard, however, remains bogged down in committee and mired in controversy, leading many users to grow disheartened and lament the continued lack of open architecture.

But the debate itself has already greatly improved communications and furthered the I&C business down the "open" path. Even without a bureaucratically dictated standard, a handful of de facto standards are emerging, and "interoperability" is more of a reality today than it was just a few years ago. In fact, users who hold off digital upgrades in anticipation of the fieldbus standard may be forever resigned to their pneumatic or electromechanical systems.

True interoperability, experts note, is a marketing dichotomy that will never really be resolved. Major vendors will release products that have some degree of interoperability, in response to users' incessant demands, but inevitably they will retain the best performance for their own products when used as a family. In other words, a valve from one company may work with another's control system, but the best performance will be available only when that valve and control system are supplied by the same firm.

Ultimately, industry observers agree, true standards will not be decided by a bureaucratic committee, but by market acceptance—consider DOS on personal computers, VHS on video recorders, and 4-20-mA analog data transmission, all of which gained worldwide acceptance without a single committee meeting.

New hardware/new thinking

As the above plant profiles reflect, there have been many successful retrofits of digital-based I&C. But installation of the new technology is not always a smooth, seamless transition. And once installed, much of its full potential may remain under-utilized—industry experts estimate that more than 80% of the capability in today's DCSs lies untapped. The problem, according to many, is that old ways of thinking aren't always tossed aside along with the antiquated hardware.

Many system designers, for example, continue to use outdated analog-type control strategies with the new digital-based hardware. Advanced strategies—such as rule-based techniques, Kalman filtering with optimal control, and fuzzy logic—should be applied to tap the full potential of microprocessor-based equipment. Compared to conventional PID algorithms, advanced strategies can provide faster response to load changes, reduced wear and tear on equipment, and improved heat rate.

New ways of thinking must be applied by project managers too, because ultimately, how an advanced controls system is implemented is as important as how it is designed. The old approach essentially went like this: A controls engineer met with the owner, went away to concentrate on a technical solution, and returned months later with a set of specifications and a Request for Proposal (RFP). The owner then contracted with the lowest bidder responding to the RFP, who installed the system. Once a brief startup test was completed, the controls engineer and the contractor departed the facility, leaving ill-prepared and puzzled O&M crews behind.

Joe meets Chip

Major cause of their bewilderment: Operators who came of age in the BC-era (before computers) typically feel more comfortable with rheostats and on/off switches than they do with computer chips. Also, maintenance technicians often lack the training and education necessary to troubleshoot and repair the new, sophisticated hardware and software. If the human factors are not addressed, operators may bypass or de-energize the new controls, preferring to run the facility with original, familiar equipment. Maintenance technicians, for their part, may neglect the digital systems or generously apply multi-colored alligator clips until the new devices are completely bypassed.

A better approach, according to many, assigns O&M personnel to the project management team so that operators can make the transition from rheostats to keyboards, trackballs, and CRTs; maintenance technicians can learn how to troubleshoot and repair digital systems; and all plant personnel develop a sense of ownership in the new controls.

Experienced project managers suggest that plant personnel be included in the following:

- Clearly defining user requirements.
- Front-end planning that includes formal reports on design ideas and implementation plans.
- Designing the graphics that will eventually become the interface to the operator controlling the plant.
- Defining which critical loops should be

backed up by hardwired switches.

■ Choosing which existing gages and recorders should remain in the plant.

■ Touring several computer-controlled plants at local process facilities or other powerplants, where O&M personnel can discuss their concerns with fellow craftsmen.

■ Installing a PC in the control room months before the refurbishment project begins, to give the operators experience with keyboard inputs, use of a mouse, and graphical displays.

■ Establishing setpoints for alarms and trips.

Sensory overload

This last item may be the most critical, because one of the pitfalls of digital I&C is its potential to overload operators with visual and audible information. In some plants, the enormous capability of unfettered computers results in an avalanche of flashing displays and boisterous annunciators that make a routine plant startup as chaotic as a hospital emergency room. Of course, not just digital I&C systems are prone to sensory overload. Recall that one of the contributing factors to the Three Mile Island Unit 2 loss-of-coolant accident was instrumentation that overwhelmed and confused operators.

To address the human interface problem, some advanced I&C systems have built-in functions that allow operators to inhibit consequential alarms, alarms related to equipment that is stopped or under maintenance, and non-critical alarms during a high-alarm period. In addition, operators can add a mark to the display screen—similar in effect to a danger tag—to indicate that a component is out-of-service for maintenance or that it should be disregarded for some other known reason.

Where rubber meets the road

Another key to successful backfit of digital I&C is preparation work—such as field-device calibration and replacement of unsuitable final-control elements (Fig 5). A universally recognized danger is that, while massive amounts of data can be sensed in the field, transmitted to the control room, analyzed in complex algorithms, displayed on clear, colorful monitors, and sent back to the field for appropriate response, the field device itself is often faulty.

Sensors that measure the temperature, pressure, concentration, or flow and actuators that move dampers or turn valves are typically less reliable and less precise than the newly installed digital-based control system. According to one user, installing advanced I&C systems without equally meticulous attention to field devices is like "installing a $15-million dashboard in a '63 Chevy." ■

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2 J Naser and others, EPRI, Palo Alto, Calif, "Nuclear Power Plant Instrumentation and Control Upgrade Activities"

3 W G Sotos and R C Carruth, American Electric Power Co, Columbus, Ohio, "The Reactor Protection and Control Process Instrumentation Digital Upgrade Project at the Donald C Cook Nuclear Power Plant Units 1 and 2"

4 R C Szczerbicki, Gilbert/Commonwealth Inc, Reading, Pa, and others, "Successful DCS Upgrade Emphasizing Operator Interface and Simulator Training"

The following papers were presented at the *American Power Conference*, Chicago, Ill, April 1995:

5 N T Cruz and others, Hydro-Quebec, Montreal, Que, Canada, "Tracy Generating Station Main Plant DCS Control Upgrade"

6 W J Harding and others, Parsons Main Inc, Pasadena, Calif, "From Pneumatics to DCS: Upgrading the Controls on Two Older Units for Tucson Electric at the Irvington Station"

7 C S Hiester and C L Longenecker, Gilbert/Commonwealth Inc, Reading, Pa, "Control System Upgrades at Wagner Station Units 3 and 4"